TECHNICAL SUPPORT DOCUMENT AND STATEMENT OF BASIS

FOR AIR QUALITY CONTROL PERMIT NO. 33500

ISSUED TO ARIZONA PUBLIC SERVICE COMPANY - CHOLLA POWER PLANT

March 6, 2006
(Draft for EPA Review)

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I. INTRODUCTION

This permit is a permit renewal of Permit No. 1000108, the original air quality Title V permit issued to Arizona Public Service Company (APS), the Permittee, for operation of its Cholla Power Plant (Cholla), located approximately two miles east of the town of Joseph City on Interstate 40, in Navajo County, Arizona, and approximately 200 miles northeast of Phoenix at an elevation of 5019 feet above sea level.

A. Company Information

Facility Name:	Cholla Power Plant
Mailing Address:	P.O. Box 188 Mail Station 4451 Joseph City, Navajo County, AZ 86032
Facility Address:	I-40 Frontage Road Joseph City, Navajo County, AZ 86032

B. Attainment Classification

The Cholla Power Plant area is designated by the Environmental Protection Agency (EPA) as an attainment area for all criteria pollutants.

C. This permit largely reproduces the original Title V permit with exception of the following additions:

1. Particulate matter compliance assurance monitoring (CAM) requirements for the four steam boiler units;
2. Alternative operating scenarios to accommodate implementation of a voluntary emissions reduction (VER) project;
3. Steam Boiler Unit 1 compliance schedule to assist Cholla in achieving compliance with 20% opacity limit, a new opacity requirement effective after April 23, 2006.

II. PROCESS DESCRIPTION

The Cholla Power Plant presently consists of four coal-fired steam generating units, associated air pollution control devices and auxiliary equipment necessary to produce electricity. Units 1, 2 and 3 are owned by APS and Unit 4 is owned by Pacificorp. All four units are operated by APS. Unit 1 was completed in 1962 and has a net accredited megawatt capacity of 110 megawatts. Units 2 and 3 were completed in 1978 and 1980 with net accredited megawatt capacities of 260 and 260 megawatts, respectively. Unit 4 was placed in commercial operation in 1981 with a net accredited megawatt capacity of 380 megawatts. As for Unit 5, which was then permitted by USEPA under EPA PSD Permit (NSR 4-102, AZP 78-01) and by the Arizona Department of Health Services (ADHS) under Installation Permit No. 1116, preliminary construction was commenced in 1980 and further construction was halted that same year. On November 13, 1985, ADHS notified APS in writing that the ADHS installation permit was canceled and the EPA PSD permit expired on December 31, 1984.

The power generated by Cholla plant is distributed to North Phoenix, APS' Saguaro Power Plant near Red Rock, north of Tucson, Flagstaff and local communities. The maximum process rates and operating hours of the steam units at Cholla are summarized in Table 1.

Table 1: Maximum process rates[1] and operating hours

Emission Unit	Hours/yr	Gross MW	Gross MW-hr/yr
Steam Boiler Unit 1	8,760	125	1,095,000
Steam Boiler Unit 2	8,760	300	2,452,800
Steam Boiler Unit 3	8,760	280	2,452,800
Steam Boiler Unit 4	8,760	425	3,723,000
Total			9,723,600

1 The maximum process rates listed in the table are estimates and should not be used as operating limits of any kind.

A. Process

Cholla is a Steam Electric Station, Standard Industrial Code (SIC) 4911 Electric Generation, consisting of four units (Units 1, 2, 3 and 4) which are coal-fired steam boilers with Source Classification Code (SCC) #1-01-002-26. Pulverized coal is tangentially fired into the dry bottom furnace of each unit. The closed coupled over-fired air (OFA) is applied to Units 2, 3 and 4. Historically, coal has been obtained from the McKinely Mine near Gallup, New Mexico. Due to unexpected shortfalls in coal output from this historic supplier, APS began and continues purchasing coal from other suppliers as needed. The coal is transported to Cholla using trains and unloaded at a "coal handling" facility which includes a Coal Preparation Plant that directs coal to the four units, a low sulfur coal pile, or a main coal pile. Two track feeders systems, "old" and "new", are used in directing the coal. The old track feeders can send coal to the four units or to the low sulfur coal pile where it can later be reclaimed, while the new track feeders can send coal to the four units or the main coal pile. The main coal pile contains approximately a 45 day supply of coal. Coal unloaded at the coal handling facility is released through the bottom of the train rail cars to one of two large grates known as grizzlies. The coal collected below the grizzly at the old track feeders is loaded to a coal conveying belt which travels to coal crusher tower #1 where, the coal can be directed either to the low sulfur coal pile or it can be crushed and directed to the Unit 1 silos or to coal crusher tower #2 where it can be conveyed to the silos for Units 2, 3, or 4. Reclaim off of the low sulfur pile, which is uncrushed, is pushed by dozer into the grizzly at the old track feeders and thereby enters the coal handling system via crusher tower #1 where it is crushed and then directed to the Unit 1 silos or via a reversible belt to crusher tower #2 for transport to Units 2-4. Alternately, coal from the low sulfur pile can be loaded into rail cars then released through either the old or new track feeders. The coal collected below the grizzly at the new track feeders is loaded to a coal conveying belt which travels to coal crusher tower #2. The crusher tower reduces the size of the coal before transporting the coal to Unit 1 (via crusher tower #1) or to the transfer tower #2 which sends it to the main pile or sends the coal to Units 2, 3, and 4 via the transition tower. Reclaim off of the bottom of the main pile goes to transfer tower #2 (via crusher tower #2) and is transported to Units 1-4. The crusher/transfer towers coal conveyor belts feed the top of coal silos of each steam boiler unit silos. All unit silos feed coal gravitationally to feeders which supply each pulverizer where the coal is ground to the consistency of talcum-powder before firing in the furnace. Emergency diesel generators are located at Units 2, 3, and 4 for purposes of safely shutting a Unit down in a loss of off-site power.

All four units at Cholla combust bituminous or sub-bituminous coal to heat high purity water to create super-heated steam which is used as the thermodynamic medium that drives the turbines/generators to produce electricity. Unit 1 uses natural gas as the warm-up/ stabilization fuel and Units 2, 3, and 4 use diesel fuel #2. All warm-up/ stabilization fuels are fired less than one percent of total unit operating time. Historical operating data indicates this to be approximately 0.7 percent of total heat input on Unit 1 and approximately 0.3 percent on Units 2, 3, and 4. Condenser cooling for Units 1 and 2 are provided by Cholla Lake, while Unit 3 and 4 have mechanical draft cooling towers with Unit 3 receiving make-up water from the lake and Unit 4 from the well field.

Unit 4 has a waste oil burning system which injects on-spec used oil and/or used oil fuel into the furnace for energy recovery purposes, and is co-fired with coal and performed on a periodic basis. The total heat input from this activity is typically less than 0.1 percent of total heat input to Unit 4 on an annual basis. Diesel fuel is used in the emergency generators located at Units 1 through 4.

Table 2 below presents a list of different operating scenarios for all units and Table 3 below lists the maximum process rates and typical fuel parameters for the boilers.

Table 2: Operating Scenarios

Source	Startup and Stabilization	Normal Operating Scenarios	Alternate Operating Scenarios
Steam Unit 1	Natural gas	Coal	
Steam Units 2 and 3	Fuel Oil No. 2	Coal	
Steam Unit 4	Fuel Oil No. 2	Coal	Co-firing coal and used oil
			Co-firing coal and used oil fuel

Note: Used oil and/or used oil fuel may be burned up to a maximum feed rate of 20 gallons per minute while co-firing coal at a minimum of 230 gross MW.

Table 3 – Boiler Maximum Process Rates and Typical Fuel Parameters

Description	Unit 1	Unit 2	Unit 3	Unit 4	Whole Plant
Maximum rated hourly process rate, MMBtu/hr	1,270	2,938	2,929	4,268	11,405
Maximum annual process rate, MMBtu/yr	11,125,200	25,736,880	25,658,040	37,387,680	99,907,800
Maximum hourly coal feed rate, lb/hr	138,800	334,000	333,000	485,000	1,290,800
Maximum annual coal usage, ton/yr	607,944	1,492,920	1,458,540	2,124,300	5,653,704
Gross Megawatt rating, MW	125	300	285	425	1,122
Heating value of coal (Btu/lb)	8,800 to 11,500	8,800 to 11,500	8,800 to 11,500	8,800 to 11,500	Na
Maximum feed rate of used oil, gallons/minute	Na	na	Na	20	20
Maximum annual usage of used oil, 10^3 gallons/yr	Na	na	Na	200	200
Heat value of fuel oil no. 2, Btu/gallon	Na	140,000	140,000	140,000	Na
Sulfur content of coal, weight percentage	0 to .8	0 to 1.2	0 to .7	0 to .7	Na
Ash content of coal, weight percentage	0 to 22%	0 to 22%	0 to 22%	0 to 22%	0 to 22%
Moisture content of coal, weight percentage	10 to 30	10 to 30	10 to 30	10 to 30	10 to 30

B. Coal Supply

The four Cholla Units typically burn 3.5 to 4.0 million tons of coal annually or about 85% of the total potential burn rate of approximately 5.6 million tons. Cholla currently purchases the majority of the coal supply from the Pittsburg & Midway Coal Mining Co.'s

(P&M) McKinley Mine. Historically, Cholla has acquired coal from other sources when P&M has been unable to meet its supply obligations, or market conditions are favorable.

In anticipation of the impending expiration of the P&M contract in 2007, Cholla is considering other coal suppliers to supply the coal requirements for the future. Two of these other suppliers, historically and for the projected future, are the coal beds found in the Powder River Basin (PRB) located in the state of Wyoming and the Lee Ranch Mine (LR) situated in north western New Mexico. Table 4 presents the typical characteristics of the coal from these mines.

Table 4: Typical Coal Quality

Coal Data	**Lee Ranch**	**McKinley**	**PRB – Black Thunder**
Sulfur	1.01%	0.43%	0.32%
Btu/lb	9,154	9,674	8,800
SO2 in coal (lb/MMBtu)	2.210	0.890	0.730
Ash	17.3%	14.7%	5.6%
Moisture	15.5%	13.9%	26.8%

C. Air Pollution Control Equipment

Cholla currently utilizes for particulate matter emissions control, the mechanical dust collectors and Venturi flooded disc scrubbers at Units 1 and 2 and the electrostatic precipitators at Units 3 and 4. For sulfur dioxide emissions removal, Cholla resorts to the lime absorber towers. Units 2 and 3 share a common stack and Unit 3 flue gases are not scrubbed. Instead, coal with low sulfur will be combusted if Unit 3 is operated alone. Table 5 summarizes the current controls in use and their rated removal efficiency.

Table 5: Current Air Pollution Controls

Equipment	PM	SOx	NOx
Unit 1	Primary - Mechanical dust collector, 55% design efficiency Secondary - Venturi flooded disc scrubber, 98% particulate removal	2 Venturi Flooded disc scrubbers/ absorber with lime reagent, 80% SO2 removal	N/A
Unit 2	Primary - Mechanical dust collector, estimated 70% efficiency Secondary - Venturi flooded disc scrubber, 98% particulate removal	4 Venturi Flooded disc scrubbers/ absorber with Lime reagent, 90% SO2 removal	N/A
Unit 3	Hot side Electrostatic Precipitator, 99% particulate removal	Use of low sulfur coal when Unit 3 is operated alone	N/A
Unit 4	Hot side Electrostatic Precipitator, 99% particulate removal	Slip - stream absorber with Lime reagent, 95% SO2 removal	N/A
Fly ash Silo	Baghouse	N/A	N/A
Lime Silo	Baghouse	N/A	N/A
Lime Slaker Vent	Wet scrubber	N/A	N/A
Coal Handling Facility	Baghouse or wetting systems with chemical suppressant	N/A	N/A

Cholla will implement a voluntary emissions reduction (VER) project during the course of the renewal permit to upgrade its pollution control capability. The project, which is summarized in Table 6, will include, among other things, installation of baghouses at Units 1, 3 and 4 and installation or expansion of SO_2 absorbers at Units 1, 3 and 4. With no emissions increase of any criteria pollutants, the project does not constitute "Major Modifications" pursuant to A.A.C. R18-2-101.63. The permit renewal establishes alternative operating scenarios as permit conditions to accommodate for the operation and maintenance of the new control equipment.

Table 6: Voluntary Emissions Reduction Project Summary

Pollution Control Equipment	Unit	Projected Date Operational	Expected Emission Rates/Removal Efficiencies
Upgrade SO_2 Scrubber to 90% Removal	1	December 31, 2007	0.24 lbs/MMBtu @ 90% Removal
Install Baghouse	1	December 31, 2007	0.03 lbs/MMBtu
New SO_2 Absorber (100% of Flue Gas)	4	December 31, 2008	0.15 lbs/MMBtu Design Outlet Emission Rate
Install Baghouse	4	December 31, 2008	0.03 lbs/MMBtu
New SO_2 Absorber	3	December 31, 2009	0.15 lbs/MMBtu Design Outlet Emission Rate
Install Baghouse	3	December 31, 2009	0.03 lbs/MMBtu

III. EMISSIONS

As described in Section I, the Cholla operation burns fossil fuel to produce electricity. The fossil fuel combustion results in emissions of a number of criteria air pollutants which mainly include particulate matter (PM)/particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compound (VOC). Table 7 summarizes potential to emit (PTE) of the criteria air pollutants under the current control and after the VER project discussed in Section II. Typical operating parameters of the turbines and the steam units given in Table 3 were used in the PTE calculation. The reader is advised to peruse the permit application for detailed emissions calculations.

The VER project to be implemented at Cholla during the course of the permit constitutes a physical change or change in the method of operation of the Cholla facility. However, the future (post-VER) actual PM/PM_{10} and SO_2 emissions are projected to decrease as a result of the change. Pursuant to A.A.C. R18-2-101.63 definition, the project is not a “major modification” and thus, the A.A.C. Title 18, Chapter 2, Article 4 analysis (Prevention of Significant Deterioration implication) is not required for this permit action. Table 8 outlines the current (pre-VER) and future actual emissions, calculated consistent with the WEPCO approach. A detailed calculation is presented in Appendix “A” of this document.

IV. COMPLIANCE CERTIFICATION

APS-Cholla has certified in Section 5 and Appendix 13 of the permit application that it is in compliance with and will continue to comply with all applicable requirements identified in the application. For those applicable requirements that become effective during the permit term, Cholla will come into compliance in a timely manner. One such requirement identified is the new 20% opacity limit specified in A.A.C. R18-2-702.B.3 to be effective after April 23, 2006. Cholla is currently capable of controlling the Unit 1 flue gas opacity to below 40 percent by operating and maintaining the mechanical dust collectors/lime slurry scrubber. In order to achieve compliance with the new opacity limit, Cholla plans to replace the current control device with fabric filter control according to the compliance schedule presented in Table 9. Semiannual progress reports are required in this permit for the Department to monitor development of the fabric filter project.

Table 7: PTE Summary

Emissions Unit		Pollutant	Current (Pre-VER) PTE (tpy)	New (Post-VER) PTE (tpy)
Unit 1		PM_{10}	1,222.02	166.88
		SO_2	1,446.28	1,335.02
		NOx	2,503.17	2,503.17
		VOCs	0.04	0.04
		CO	151.99	151.99
Unit 2		PM_{10}	1,286.84	1,286.84
		SO_2	3,088.43	3,088.43
		NOx	5,790.80	5,790.80
		VOCs	0.61	0.61
		CO	365.73	365.73
Unit 3		PM_{10}	1,154.61	384.87
		SO_2	15,394.82	1,539.48
		NOx	5,773.06	5,773.06
		VOCs	.61	.61
		CO	364.64	364.64
Unit 2/3		SO_2	See U2 and U3	See U2 and U3
Unit 4		PM_{10}	1,682.45	560.82
		SO_2	14,955.07	3,364.89
		NOx	8,412.23	8,412.23
		VOCs	.83	.83
		CO	531.08	531.08
Flyash Silo Baghouse		PM	.00002	.00002
Lime Silo Baghouse		PM	.00001	.00005
Lime Slaking Wet Scrubber		PM	.00004	.00024
U3 Cooling Tower		PM	36.2	36.2
U4 Cooling Tower		PM	37.4	37.4
Coal Handling System	Unloading, Conveying and Crushing Coal	PM	1.0078	1.0078
	Coal Storage Wind Erosion, Moving Coal, and Stacking Coal	PM	62.2	62.2

Table 8: Emissions Comparison Before and After the VER Project

Emissions Unit	Pollutant	Current Actual (Pre-VER) Emission (tpy)	Future Actual (Post-VER) Emission (tpy)	Net Emissions (tpy)
Unit 1	PM_{10}	57	57	0
	SO_2	875	875	0
Unit 2	PM_{10}	131	131	0
	SO_2	1408	1408	0
Unit 3	PM_{10}	79	79	0
	SO_2	9214	1210	-8004
Unit 4	PM_{10}	264	264	0
	SO_2	10143	2567	-7576

Table 9: Unit 1 Fabric Filter Project Timeline

Actions with milestones	Completion date
Secure the engineering, procurement, and construction (EPC) contract with Alstom	Completed
Demolition and site preparation	Completed
Piling and foundations	June 1, 2006
Complete detailed engineering	June 30, 2006
Completion of construction of baghouse to the point that it is ready for tie into the boiler during an outage	December 31, 2006
Beginning tie into boiler (outage in spring 07 but looking at delaying until the fall after summer peak due to lead time of non-baghouse outage items)	November 1, 2007
Commission of the new baghouse (startup date following tie in)	December 15, 2007
Conduct stack test to demonstrate compliance with 20% opacity limit	December 30, 2007

V. APPLICABLE REGULATIONS

APS-Cholla has identified all applicable regulations that apply to its facility in Appendix 13 of the permit application. The permit is a renewal of the Title V Permit No. 1000108 and incorporates all regulations that were determined applicable in that permit. Please refer to the technical support document (TSD) of Permit No. 1000108 for applicability verification. Additionally, being a Title V permit renewal after April 20, 1998, this permit action also triggers applicability of the compliance assurance monitoring required under 40 CFR 64.

VI. PREVIOUS PERMITS AND CONDITIONS

APS-Cholla was issued its first Title V Permit No. 1000108 on January 19, 2000. During the permit term of the original Title V permit, Cholla requested and received several permit amendments as follows. This permit renewal incorporates all conditions from the amendments.

A. Administrative amendment #1001445 was issued on November 21, 2000, allowing a change in ownership from Arizona Public Service to Pinnacle West Energy Corporation.

B. Minor revision #1001444 was issued on April 9, 2001, allowing for re-configuration of Unit #1's boiler fans.

C. Administrative amendment #1001782 was issued on January 8, 2002 to correct two typographical discrepancies.

D. Significant revision #27490 was issued on January 30, 2003, authorizing Cholla to use SO_2 data from a CEMS installed at Unit #1 scrubber inlet, instead of coal analysis data, for SO_2 removal efficiency determination, and to add seven new baghouses to the coal handling system.

VII. COMPLIANCE ASSURANCE AND PERIODIC MONITORING

A. Steam Unit 1

<u>Opacity</u>: Unit 1 is subject to 40% opacity limit on or before April 23, 2006 and 20% opacity limit after April 23, 2006 in accordance with A.A.C. R18-2-702.B.2 and 3. Cholla is required under A.A.C. R18-2-313.C.1.a to maintain and operate a continuous monitoring system for opacity. The monitoring system is required to meet the requirements of A.A.C. R18-2-313.D.1, which references to 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 1.

<u>SO2</u>: The unit is subject to the sulfur dioxide standard of 1.0 lb/MMBtu heat input under A.A.C. R18-2-703.G.1 while burning coal. Cholla is required under A.A.C. R18-2-313.C.1.b to maintain and operate a continuous monitoring system for sulfur dioxide. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A through C. The source is also required to meet 80% SO2 removal efficiency through the use of the control device. SO2 concentrations at inlet and outlet of the control device are monitored by CEMS to determine compliance with the SO2 removal efficiency.

<u>NOx</u>: There is no standard for NOx emissions from Unit 1 as it was built before May 30, 1972. NOx monitoring is not required, except for 40 CFR 76 NOx standards which requires compliance CEMS.

PM: The unit is subject to the particulate matter emissions standard set forth in A.A.C. R18-2-703.C.1. The unit also has potential pre-control device PM emissions that are greater than 100 tons per year, the major source threshold, and pursuant to 40 CFR 64.2(a), the compliance assurance monitoring (CAM) is required. The opacity of exhaust gases is selected to be primary performance indicator of the Unit 1 Venturi scrubbers and the flooded disc pressure drop (Δp) and slurry flow to be secondary indicators. Using COMS data, Cholla is to calculate block 1-hour average opacities excluding periods of boiler startup, shutdown, and malfunction. If at any point, excluding periods of startup, shutdown, and malfunction, the opacity average exceeds 19%, then Cholla will need to (1) check and record the flooded disc Δp and slurry flow for each flooded disc and (2) record the operational status of Unit 1 boiler (i.e. load change increase or decrease). Block 1-hour average opacities of 20% or greater and Δp is less than 8 inches of water column or slurry flow is equal to or less than 1,500 gallons per minute per pump is to be considered an excursion. In conjunction with the Voluntary Emission Reduction (VER) project described in II.C of this document, when the new baghouse is in service to replace the Venturi scrubbers, while continue to observe the 1-hour block opacity average from COMS data, Cholla is to begin continuous monitoring of induced draft (I.D.) fan pressure across the baghouse and periodic reading of magnahelic gauges that indicate the condition of each compartment of the baghouse. The key elements of the monitoring approach are presented in Table 10.

B. Steam Unit 2

Opacity: Unit 2 is subject to an opacity standard of < 20% except for one six-minute period per hour of not more than 27% opacity. Cholla is required under 40 CFR 60.45(a) to maintain and operate a continuous monitoring system for opacity. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 1.

SO2: The unit is subject to the sulfur dioxide standard of 0.8 lb/MMBtu heat input and 90% removal efficiency. Cholla is required to maintain and operate a SO2 continuous monitoring system consistent with Subpart Da requirements at inlet and outlet of the sulfur dioxide control device that will be utilized to determine compliance with the sulfur dioxide emission and removal efficiency limit. The SO2 CEMS is required to meet the requirements of 40 CFR 60.13, 40 CFR 60, Appendix F, and 40 CFR 75, Appendix A through C. In conjunction with the SO2 CEMS on Unit 3, Cholla is also required to continuously monitor the megawatt weighted average emissions of sulfur dioxide from the common stack for Units 2 and 3 to determine compliance with a “bubbled” standard of 0.8 lb/MMBtu heat input.

NOx: The unit is subject to the NOx standard of 0.70 lb/MMBtu heat input in 40 CFR 60.44(a)(3) while burning coal. Cholla is required under 40 CFR 60.45(a) to maintain and operate a continuous monitoring system for NOx. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A through C.

Table 10: CAM Plan for Fabric Filter Baghouse

General Criteria	Performance indicator	Stack opacity at each of Steam Boiler Units 1, 3 and 4 stacks	Induction draft (ID) fan suction pressure at each of Steam Boiler Units 1, 3 and 4	Individual baghouse compartment magnahelic differential pressure gage readings
	Measurement Approach	Opacity values from the Continuous Opacity Monitor (COM) at each boiler unit are monitored.	This is a direct indication of the condition of the baghouse filters for each boiler unit.	Each baghouse compartment is equipped with a magnahelic differential pressure gauge that continuously measures the differential air pressure across the compartment.
	Indicator range(s) and excursion definition	An excursion is defined as block 1-hour opacity average that exceeds 10%, excluding periods of startup, shutdown, and malfunction. An excursion requires investigation of the compartment pressure differential values for decreases in differential pressure. Repairs or adjustments are made as necessary. A log of the corrective action(s) will be maintained.	An excursion is defined as an ID fan suction pressure reading that exceeds a unit specific pressure level in inches water column or a sudden drop of more than 1.0 inch in the ID fan suction pressure, excluding periods of startup, shutdown, and malfunction.	An excursion is defined as a differential pressure value of more than ½ inch of water column above the resting or cleaning mode pressures, excluding periods of startup, shutdown, and malfunction. Investigation is initiated to locate the cause
Performance Criteria	Data representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of an increase in particulate matter emissions.	A high pressure indicates bags may be clogged and particulate matter may be being forced through the bag fabric. A sudden decrease in fan suction pressure indicates a possible bag break or seal loss. Particulate removal rates should remain consistent until a problem is detected.	From the standpoint of particulate removal efficiency, only a reading indicating a loss of compartment integrity shows a reduction in the overall efficiency of the baghouse. Readings indicating a compartment is clogged may not indicate degradation of overall baghouse particulate removal efficiency, but do signal the need for investigation.
	Verification of monitoring status	Effective upon commissioning of service of a fabric filter control device at each affected boiler unit.	Effective upon commissioning of service of a fabric filter control device at each affected boiler unit.	Effective upon commissioning of service of a fabric filter control device at each affected boiler unit.
	QA/QC practices	The COM equipment and data quality assurance is in conformance with 40 CFR Part 60 Appendix B & F.	Annual calibration of ID fan suction pressure gauges.	Annual calibration of the baghouse magnahelic gages. Operators check magnahelics on routine rounds each shift. The most frequent problem identified is plugged sensing lines which are cleared upon detection.
	Monitoring frequency	Continuous recording of opacity.	Continuous, with hourly recording of pressure values.	Cell magnahelic values recorded once per shift.
	Data collection procedures	The opacity monitor continuously records the average for each one (1) minute interval.	Operator records readings on the log sheet hourly.	Magnahelic readings are recorded once per shift. Once per week the operator records the in-service, reverse air cleaning, and at rest magnahelic readings on each cell, and notes any discrepancies. Plant management reviews this data to identify issues that need to be addressed immediately and those that can be added to the next scheduled maintenance work list.
	Averaging period	Block one hour.	N/A	N/A

PM: The unit is subject to the particulate matter emissions standard of 0.10 lb/MMBtu set forth in 40 CFR 60.42(a)(1). The unit also has potential pre-control device PM emissions that are greater than 100 tons per year, the major source threshold, and pursuant to 40 CFR 64.2(a), the compliance assurance monitoring (CAM) is required. The opacity of exhaust gases is selected to be primary performance indicator of the Unit 2 Venturi scrubbers and the flooded disc pressure drop (Δp) and slurry flow to be secondary indicators. Using COMS data, Cholla is to calculate block 1-hour average opacities excluding periods of boiler startup, shutdown, and malfunction. If at any point, excluding periods of startup, shutdown, and malfunction, the opacity average exceeds 16%, then Cholla will need to (1) check and record the flooded disc Δp and slurry flow for each flooded disc and (2) record the operational status of Unit 2 boiler (i.e. load change increase or decrease). Block 1-hour average opacities of 17% or greater and Δp is less than 15 inches of water column or slurry flow is equal to or less than 4,000 gallons per minute per pump is to be considered an excursion.

C. Steam Unit 3

Opacity: Unit 3 is subject to an opacity standard of < 20% except for one six-minute period per hour of not more than 27% opacity. Cholla is required under 40 CFR 60.45(a) to maintain and operate a continuous monitoring system for opacity. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 1.

SO2: Sharing a common stack with Unit 2, the unit is subject to the sulfur dioxide standard of 1.2 lb/MMBtu heat input in accordance with A.A.C. R18-2-903.3.c.i while burning coal. Cholla is required to maintain and operate a SO2 continuous monitoring system consistent with 40 CFR 60.47a (“Emission monitoring”) to continuously monitor the sulfur dioxide emissions from Unit 3. The SO2 CEMS is also required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A through C. In conjunction with the SO2 CEMS on Unit 2, the source is also required to continuously monitor the megawatt weighted average emissions of sulfur dioxide from the common stack for Units 2 and 3 to determine compliance with a “bubbled” standard of 0.8 lb/MMBtu heat input.

NOx: The unit is subject to the NOx standard of 0.70 lb/MMBtu heat input in 40 CFR 60.44(a)(3) while burning coal. Although Cholla is exempted from installation of a continuous NOx monitoring system under 40 CFR 60.45(b)(3), periodic monitoring for NOx emissions is required under A.A.C. R18-2-306.A.3.c. The Acid Rain Program NOx CEMS will be used to meet the periodic monitoring requirement. For QA/QC purpose, the monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A through C.

PM: The unit is subject to a standard of 0.10 lb/MMBtu set forth in 40 CFR 60.42(a)(1). The unit also has potential pre-control device PM emissions that are greater than 100 tons per year, the major source threshold, and pursuant to 40 CFR 64.2(a), the compliance assurance monitoring (CAM) is required. The opacity of exhaust gases is selected to be primary performance indicator of the Unit 3 ESP and the operational status of transformer/rectifier (TR) and rapper and TR amps and volts to be secondary indicators. Using COMS data, Cholla is to calculate block 1-hour average opacities excluding periods of boiler startup, shutdown, and malfunction. If at any point, excluding periods of startup, shutdown, and malfunction, the opacity average exceeds 16%, then Cholla will need to (1) Compare the TRs that are currently in service to the TRs that were in service during the previous hour to determine if any additional TRs were removed from service. If TRs were removed from service or tripped due to reasons unrelated to startup, shutdown, or malfunction, then an excursion has occurred and need to be reported; or (2) Compare current rapper operation with the rapper operation during the previous hour to determine if any changes occurred. If rappers were removed from service or tripped due to reasons unrelated to startup, shutdown, or malfunction, then an excursion has occurred and need be reported; or (3) Compare current TR amps and volts with the amps and volts during previous hour if available, or the most recent available amps and volts recorded to determine if a change occurred. If TR's amps and/or volts were changed due to reasons unrelated to startup, shutdown, or malfunction, then an excursion has occurred and need be reported; (4) If no ESP abnormalities are discovered during the above described investigations, then no excursion has occurred. In conjunction with the Voluntary Emission Reduction (VER) project described in II.C of this document, when new baghouse is in service to replace the Unit 3 ESP, while continue to observe the 1-hour block opacity average from COMS data, Cholla is to begin continuous monitoring of induced draft (I.D.) fan pressure across the baghouse and periodic reading of magnahelic gauges that indicate the condition of each compartment of the baghouse. The key elements of the monitoring approach are presented in Table 10.

D. Steam Unit 4

Opacity: Unit 4 is subject to an opacity standard of < 20% except for one six-minute period per hour of not more than 27% opacity. Cholla is required under 40 CFR 60.45(a) to maintain and operate a continuous monitoring system for opacity. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 1.

SO2: The unit is subject to the sulfur dioxide standard of 0.8 lb/MMBtu heat input in A.A.C. R18-2-903.1 while burning coal. Cholla is required under 40 CFR 60.45(a) to maintain and operate a continuous monitoring system for sulfur dioxide emissions. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A through C.

NOx: The unit is subject to the NOx standard of 0.70 lb/MMBtu heat input in 40 CFR 60.44(a)(3) while burning coal. Although Cholla is exempted from installation of a continuous NOx monitoring system under 40 CFR 60.45(b)(3), periodic monitoring for NOx emissions is required under A.A.C. R18-2-306.A.3.c. The Acid Rain Program NOx CEMS will be used to meet the periodic monitoring requirement. For QA/QC purpose, the monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A through C.

PM: Unit 4 is subject to a standard of 0.10 lb/MMBtu set forth in 40 CFR 60.42(a)(1). The unit also has potential pre-control device PM emissions that are greater than 100 tons per year, the major source threshold, and pursuant to 40 CFR 64.2(a), the compliance assurance monitoring (CAM) is required. The opacity of exhaust gases is selected to be primary performance indicator of the Unit 4 ESP and the operational status of transformer/rectifier (TR) and rapper and TR amps and volts to be secondary indicators. Using COMS data, Cholla is to calculate block 1-hour average opacities excluding periods of boiler startup, shutdown, and malfunction. If at any point, excluding periods of startup, shutdown, and malfunction, the opacity average exceeds 16%, then Cholla will need to (1) Compare the TRs that are currently in service to the TRs that were in service during the previous hour to determine if any additional TRs were removed from service. If TRs were removed from service or tripped due to reasons unrelated to startup, shutdown, or malfunction, then an excursion has occurred and need to be reported; or (2) Compare current rapper operation with the rapper operation during the previous hour to determine if any changes occurred. If rappers were removed from service or tripped due to reasons unrelated to startup, shutdown, or malfunction, then an excursion has occurred and need be reported; or (3) Compare current TR amps and volts with the amps and volts during previous hour if available, or the most recent available amps and volts recorded to determine if a change occurred. If TR's amps and/or volts were changed due to reasons unrelated to startup, shutdown, or malfunction, then an excursion has occurred and need be reported; (4) If no ESP abnormalities are discovered during the above described investigations, then no excursion has occurred. In conjunction with the Voluntary Emission Reduction (VER) project described in II.C of this document, when new baghouse is in service to replace the Unit 4 ESP, while continue to observe the 1-hour block opacity average from COMS data, Cholla is to begin continuous monitoring of induced draft (I.D.) fan pressure across the baghouse and periodic reading of magnahelic gauges that indicate the condition of each compartment of the baghouse. The key elements of the monitoring approach are presented in Table 10.

E. Other Point, Non-Point and/or Fugitive PM Emission Sources

Pursuant to A.A.C. R18-2-306.A.3.c, Cholla is required to conduct periodic monitoring at those other particulate matter emission sources for which the applicable requirement does not require periodic testing or instrumental or non-instrumental monitoring. These include all point, non-point and/or fugitive PM emission sources at the cooling towers 3 and 4, coal preparation plant, fly ash handling facility, lime handling and slaking facility, fugitive dust sources, and internal combustion engines. The periodic monitoring is carried out through a visual observation plan that identifies a central lookout station or multiple observation points as follows:

Point #1: Personnel overpass located at coal handling (North East area of plant)

Sources observed include coal unloading, coal crushers, coal stacking, coal reclaiming, Unit 1 coal handling/silo baghouse exhaust, coal transfer tower #1, all coal drop points from coal unloading to Unit 1 silos, to transition tower, and to coal stacker, Unit 1 flyash handling system, flyash silo baghouse exhaust, lime silo baghouse exhaust, lime slaking wet scrubber exhaust, coal storage pile, main entrance roadway and main south/north plant road.

Point #2: North of Unit 3 weld shop and south of Unit 2/3 diesel generators

Sources observed include Unit 2/3 diesel generators, Unit 2 and 3 flyash handling.

Point #3: South east corner of Unit 4 auxiliary bay

Sources observed include Unit 2, 3, and 4 coal handling system baghouse exhausts, Unit 4 diesel generator, Unit 4 Eastern flyash handling, main East/West plant roadway.

Point #4: South West corner of Unit 4 Auxiliary Bay

Sources observed include Unit 3 and 4 cooling tower, laydown areas, Unit 4 Western flyash handling.

The plan requires Cholla to make a weekly survey of the visible emissions at the above described vintage points. If there are no visible emissions, then Cholla is required to record the date, time, and results of the survey. If Cholla finds that on an instantaneous basis the visible emissions are in excess of the applicable opacity limit, then a six-minute Method 9 observation is required to be made. If this observation indicates opacity in excess of the applicable opacity limit, then Cholla is required to report it as excess emissions. If Cholla finds that the visible emissions are less than the applicable opacity limit, then Cholla is required to record the source of emission, date, time, and result of the observation.

VIII. TESTING REQUIREMENTS

Cholla is required to conduct annual performance tests for stack emissions of opacity, particulate matter, sulfur dioxide, and nitrogen oxides from all steam boiler units to demonstrate, on an annual basis, compliance with the respective emissions standards, except for sulfur dioxide emissions from units 2 and 3 stacks where SO2 emissions data collected from the SO2 CEMS can and will be used to determine compliance pursuant to 40 CFR 60, Subpart Da, and for nitrogen oxides emissions from unit 1 stack where there is no applicable standard for NOx emissions. Compliance with opacity standards is determined using EPA Reference Method 9. Performance tests for all pollutants are conducted using the procedures and methods contained in the Arizona Testing Manual or 40 CFR 60, Appendices A through F.

IX. USED OIL OR USED OIL FUEL BURNING

Unit 4 also co-fires with coal a small quantity of on-site generated used oil and/or used oil fuel for energy recovery purposes. Total heat input from this activity is typically less than 0.1 percent of total heat input to Unit 4 on an annual basis. The oil burned is required to be on specification as follows. To assure the standard to be met, Cholla is required to run sample testing semiannually for the used oil prior to burning.

A. The flash point of the oil does not fall below 100 ºF;

B. The oil does not have following constituents in excess of the following allowable levels:

1.	Arsenic	5 ppm
2.	Cadmium	2 ppm
3.	Chromium	10 ppm
4.	Lead	100 ppm
5.	PCBs	2 ppm

X. AMBIENT AIR QUALITY IMPACT ANALYSIS

Section II of this document discussed that Cholla will implement a voluntary emissions reduction (VER) project during the course of this permit. Part of the project is to upgrade the plant's SO_2 scrubbing capability by either replacing or expanding the SO_2 absorbers of various boiler units, which will presumably lower the stack temperatures and flow rates and alter the plume dispersion characteristics. As a result, different ambient air quality impacts are to emerge that have not been previously analyzed. To address the post-VER ambient impacts, Cholla has submitted "Air Quality Modeling Protocol and Report" as part of the permit application that demonstrates that the emissions after implementation of the VER project will result in compliance with the National Ambient Air Quality Standards (NAAQS), PSD Class I and II increments, Class I visibility, and Arizona Ambient Air Quality Guidelines (AAAQGs). The following outlines the modeling results. For detailed discussion, please review the modeling protocol and report.

A. Modeling Summary

The ISCST3 dispersion model was used to determine the NAAQS, PSD Class II increment, and AAAQG ambient impacts. The CALPUFF model was used to determine the PSD Class I increment and visibility ambient impacts.

B. NAAQS Analysis

Modeling was made to verify that the VER project does not cause a violation of NAAQS for SO_2, PM_{10}, and lead. Results of the modeling are presented in Table 11, which show that impact results for each pollutant plus the background concentrations are below the NAAQS for all applicable averaging periods.

Table 11: NAAQS Modeling Results

Pollutant	Averaging Interval	Maximum Modeled Impact ($\mu g/m^3$)	Ambient Background ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
SO_2	3-Hour	234	163	397	1300
	24-Hour	59.5	36	95.5	365
	Annual	7.7	6.0	13.7	80
PM_{10}	24-Hour	16	66.9	82.9	150
	Annual	1.7	19.8	21.5	50
Lead	Quarter	0.0002	n/a	0.0002	1.5

C. Class I PSD Increment Analysis

There are several Class I areas near the Cholla facility, Petrified Forest being the closest (50.2 kilometer). Modeling was made to verify that the VER project does not cause a violation of Class I area PSD Increment limits for SO_2 and PM_{10}. The Class I modeling analysis follows a two-step process. First, an impact analysis of the project's net emission changes was conducted and results are compared to the EPA Class I PSD significance impact levels (SIL). If the project impacts exceed the Class I SIL for any pollutant and averaging interval, refined Class I PSD increment analyses are then performed for that pollutant and averaging interval. The SIL impact analysis shows all but the annual PM_{10} impact is above the EPA Class I SIL. A refined annual PM_{10} PSD Class I increment analysis was conducted and the results are presented in Table 12. The results show that the annual PM_{10} impact is below the required increment level.

Table 12: Class I PSD Increment Modeling Results

Pollutant	Averaging Interval	Maximum Modeled Impact ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
PM_{10}	Annual	0.13	5

D. Class II PSD Increment Analysis

Modeling was made to verify that the VER project does not cause a violation of Class II area PSD Increment limits for SO_2 and PM_{10}. Results of the modeling are presented in

Table 13, which show that impacts for each pollutant are below the Class II PSD increments for all applicable averaging periods.

Table 13: Class II PSD Increment Modeling Results

Pollutant	Averaging Interval	Maximum Modeled Impact (μg/m^3)	PSD Class II Increment (μg/m^3)
SO_2	3-Hour	152	512
	24-Hour	18.5	91
	Annual	2.2	20
PM_{10}	24-Hour	9.2	30
	Annual	0.9	17

E. AAAQG Analysis

Modeling was made to verify that the VER project does not cause a violation of AAAQG for various heavy metals and sulfuric acid mist. Results of the modeling presented in Table 14 show that the impacts from associated air toxics do not exceed AAAQG for all applicable averaging periods.

Table 14: AAAQG Modeling Results

Pollutant	Maximum Impact (μg/m^3)	Maximum Impact (μg/m^3)	Maximum Impact (μg/m^3)	AAAQG (μg/m^3)	AAAQG (μg/m^3)	AAAQG (μg/m^3)
	1-Hour	24-Hour	Annual	1-Hour	24-Hour	Annual
Max modeled Concentration	2.5	0.19	0.029	---	---	---
Arsenic (As)	0.001	0.000	0.000	0.28	0.073	0.0002
Beryllium (Be)	0.000	0.000	0.000	0.06	0.016	0.0005
Cadmium (Cd)	0.000	0.000	0.000	1.7	.11	0.00029
Chlorine (as HCL)	0.124	0.009	0.001	210	56	7
Chromium	0.003	0.000	0.000	11	3.8	n/a
Fluorine (as HF)	0.345	0.026	0.004	6	1.6	n/a
Manganese (Mn)	0.007	0.001	0.000	25	8	n/a
Nickel (Ni)	0.003	0.000	0.000	5.7	1.5	0.004
Sulfuric Acid Mist (SAM)	0.499	0.038	0.006	22.5	7.5	n/a

F. Class I Visibility Analysis

CALPUFF modeling predicts the maximum visibility impact of 0.02 deciviews at Petrified Forest Class I area, which is below the visibility significance level of 0.5 deciviews. Thus, the Class I visibility will not be adversely effected as a result of the VER project.

XI. INSIGNIFICANT ACTIVITIES

The insignificant activities are determined in the following table:

No.	Insignificant Activities	Pollutants	Verification	Comments
1	Scale Inhibitor Storage Tank	HEDP	yes	A.A.C. R18-2-101.54.j
2	Scale Inhibitor Storage Tank	HEDP,ZN&PHOSPHONATE	yes	A.A.C. R18-2-101.54.j
3	Condensate Storage Tanks	PM-10	yes	A.A.C. R18-2-101.54.j
4	Aux. Cooling System Clam Treatment	CLAM-TROL CT-1	yes	A.A.C. R18-2-101.54.j
5	Chemical Day Tanks (3 Tanks/unit)	NH3, PO4, N2H4	yes	A.A.C. R18-2-101.54.j
6	Lake Intake Clam Treatment	CLAM-TROL CT-1	yes	A.A.C. R18-2-101.54.j
7	Stack Gas Analyzers+ Gas Cylinders	SO2,NO,FLUE GAS	yes	A.A.C. R18-2-101.54.i
8	Potable Water Head Tanks	CHLORINE	yes	A.A.C. R18-2-101.54.j

No.	Insignificant Activities	Pollutants	Verification	Comments
9	Service Water Tanks	CONTAINS WELL WATER	yes	A.A.C. R18-2-101.54.j
10	De-aerator Tanks	TRACE BOILER CHEMICALS	yes	A.A.C. R18-2-101.54.j
11	Turbine Lube Oil Tanks	OIL VAPORS (VOC'S)	yes	A.A.C. R18-2-101.54.j
12	Turbine Lube Oil Vapor Extractors	OIL VAPORS (VOC'S)	no	A.A.C. R18-2-730.G
13	Generator Seal Oil Vapor Extractors	OIL VAPORS (VOC'S)	no	A.A.C. R18-2-730.G
14	Equip. Lube Oil Storage Tanks	OIL VAPORS (VOC'S)	yes	A.A.C. R18-2-101.54.c
15	Sedi. Pond Transfer Pump Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
16	Sludge Tanks(1)	PM-10	yes	A.A.C. R18-2-101.54.j
17	Demister Water Tank	PM-10	yes	A.A.C. R18-2-101.54.j
18	Diesel Fuel Storage Tank (Small)	FUEL OIL (VOC'S)	yes	A.A.C. R18-2-101.54.j
19	Fuel Oil Storage Tank (Large)	FUEL OIL (VOC'S)	414,540 gal.	A.A.C. R18-2-101.54.j
20	Gasoline, Diesel Storage Tank(ast)	GAS, DIESEL (VOC'S)	yes	A.A.C. R18-2-101.54.b, c
21	Acid and Caustic Tanks (Empty)	H2SO4, NAOH	yes	A.A.C. R18-2-101.54.j
22	Acid Tank	H2SO4	no	A.A.C. R18-2-730.G
23	Glycol Storage Tank	GLYCOL	yes	A.A.C. R18-2-101.54.j
24	Glycol Expansion Tank(2)	GLYCOL	yes	A.A.C. R18-2-101.54.j
25	Process Water Tank	PM-10	yes	A.A.C. R18-2-101.54.j
26	Boiler Feed Pump Seal Water Tank	PM-10	yes	A.A.C. R18-2-101.54.j
27	Vacuum Pumps	PM-10	yes	A.A.C. R18-2-101.54.j
28	Air Ejectors	PM-10	yes	A.A.C. R18-2-101.54.j
29	Absorber Feed Pumps Bearings	LUBE OIL VAPORS(VOC'S)	yes	A.A.C. R18-2-101.54.j
30	Scrubber Feed Pumps	LUBE OIL VAPORS(VOC'S)	yes	A.A.C. R18-2-101.54.j
31	Fire Water Diesel Pumps(2)	DIESEL FUMES(VOC'S)	yes	A.A.C. R18-2-101.54.j
32	Fire Water Tanks (2)	WATER	yes	A.A.C. R18-2-101.54.j
33	Fly Ash Blowers Oil Reservoirs	LUBE OIL VAPORS(VOC'S)	yes	A.A.C. R18-2-101.54.j
35	Locomotives(2)	DIESEL FUEL VAPORS (VOC'S)	no	A.A.C. R18-2-802
36	Street Cleaner	PM-10, VOC'S	no	A.A.C. R18-2-802
37	Road Grader from Childs/Irving Plant	PM-10, VOC'S	no	A.A.C. R18-2-802
38	Boiler Blowdowns	BOILER CHEMICALS	yes	A.A.C. R18-2-101.54.j
39	Gland Steam Condenser Exhausters	STEAM	yes	A.A.C. R18-2-101.54.j
40	Coal Silo Atmospheric Openings(5)	COAL DUST(PM-10)	no	A.A.C. R18-2-716.B.1
41	Coal Silo Vent Exhaust Fan	COAL DUST(PM-10)	no	A.A.C. R18-2-716.B.1
42	Fly Ash Silo Baghouse	FLY ASH(PM-10)	no	A.A.C. R18-2-730.A.1
43	Lime Silo Baghouse	CAO (PM-10)	no	A.A.C. R18-2-730.A.1
44	Lime Unloading	CAO (PM-10), VOC'S	no	A.A.C. R18-2-730.A.1
45	Reagent Feed Tanks Pumps(4)	VOC'S	yes	A.A.C. R18-2-101.54.j
46	Reagent Storage Tank Pumps (2)	VOC'S	yes	A.A.C. R18-2-101.54.j
47	Elemental Sulfur Tank	PM-10	yes	A.A.C. R18-2-101.54.j
48	Elemental Sulfur Tank Pump	VOC'S	yes	A.A.C. R18-2-101.54.j
49	Bottom Ash Trans., Makeup Tank	PM-10,VOC'S	yes	A.A.C. R18-2-101.54.j
50	Pyrite Transfer Tank	PM-10	yes	A.A.C. R18-2-101.54.j
51	EHC Reservoir	EHC FLUID VAPORS(VOC'S)	yes	A.A.C. R18-2-101.54.j
52	Chlorine Gas Tanks	CL2 GAS	no	112(r)
53	Lime Slaking Vent Wet Scrubber	CAO(PM-10)	no	A.A.C. R18-2-730.A.1
54	Cooling Towers	PM-10,CL2,H2SO4,DEFOAM	no	A.A.C. R18-2-730.A.1
55	Painting Hood	PM-10, VOC'S	no	A.A.C. R18-2-730.F
56	Bathroom Vents	NON-METHANE HYDROCR.	yes	A.A.C. R18-2-101.54.j
57	Aerosol Paints/brushes	VOC'S	no	A.A.C. R18-2-730.F
58	Woodworking	PM-10	yes	A.A.C. R18-2-101.54.j
59	Maintenance Shop Activities	PM-10, VOC'S	yes	A.A.C. R18-2-101.54.j
60	Electric Water Heaters		yes	A.A.C. R18-2-101.54.j
61	Electric Space Heaters		yes	A.A.C. R18-2-101.54.j
62	Battery Charging Areas	H2SO4	yes	A.A.C. R18-2-101.54.j
63	Breakers		yes	A.A.C. R18-2-101.54.j
64	Lab Chemicals	HOOD VENTS	yes	A.A.C. R18-2-101.54.i
65	ESPs	OZONE	no	Permitted activity
66	Kitchen Hoods	VOC'S	yes	A.A.C. R18-2-101.54.j
67	Charcoal Grills	PM-10,VOC'S	yes	A.A.C. R18-2-101.54.j
68	Welding Hood Exhaust	PM-10	yes	A.A.C. R18-2-101.54.j

No.	Insignificant Activities	Pollutants	Verification	Comments
69	Mercury Recovery Hood	HG	yes	A.A.C. R18-2-101.54.j
70	Pulveriser Pyrite Chutes(5)	PM-10	yes	A.A.C. R18-2-101.54.j
71	Insulation Shop Vent	PM-10	yes	A.A.C. R18-2-101.54.j
72	Boiler Casing Leaks	PM-10, SO2, NOX	yes	A.A.C. R18-2-101.54.j
73	Bottom Ash Transfer Sump	PM-10, BOILER CLEANING	yes	A.A.C. R18-2-101.54.j
74	Coal Lab Vent	PM-10	yes	A.A.C. R18-2-101.54.i
75	Misc. Steam Vents(6 -8)	BOILER CHEMICALS	yes	A.A.C. R18-2-101.54.j
76	Natural Gas Line Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
77	Parts Cleaners	EPA 2000 (VOC'S)	yes	A.A.C. R18-2-101.54.j
78	Welding Rod Fumes	PM-10	yes	A.A.C. R18-2-101.54.j
79	Acetylene Cylinders	ACETYLENE	no	112(r)
80	Boiler Drains and Vents	PM-10	yes	A.A.C. R18-2-101.54.j
81	Lake Intake Closed Sump	VOC'S	yes	A.A.C. R18-2-101.54.j
82	Lake Intake Trash Rakes	VOC'S	yes	A.A.C. R18-2-101.54.j
83	Paint Shop Hood	PM-10, VOC'S	no	A.A.C. R18-2-730.F
84	Locomotive Building Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
85	Satellite Oil/haz Waste Areas	VOC'S	yes	A.A.C. R18-2-101.54.j
86	Lube Rack(s), Lube Building Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
87	Oil Drip Racks	VOC'S	yes	A.A.C. R18-2-101.54.j
88	Portable Heaters, Propane Tanks	VOC'S	yes	A.A.C. R18-2-101.54.j
89	Track Straightener Machine	VOC'S	yes	A.A.C. R18-2-101.54.j
90	Coal Crusher Tower Lube System	VOC'S	yes	A.A.C. R18-2-101.54.j
91	Cooling Towers Fan Motors Vents-18	VOC'S	yes	A.A.C. R18-2-101.54.j
92	Unit Condensate Pump Vents(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
93	Electrical Hydraulic Control System Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
94	Boiler Feed Pump(s) Oil Cooling Vents(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
95	Instrument Air Compressor Vents	VOC'S	yes	A.A.C. R18-2-101.54.i
96	Station Air Compressors	VOC'S	yes	A.A.C. R18-2-101.54.j
97	Turbine Oil Cooling Vent(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
98	Closed Cooling Water Tank Vent	PM-10	yes	A.A.C. R18-2-101.54.j
99	ID/FD Fans Oil Cooling Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
100	Air Preheater Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
101	Air Preheater Guide Bearing Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
102	O/W Separators (2)	VOC'S	yes	A.A.C. R18-2-101.54.j
103	Control Room Bathroom Vents	NON-METHANE HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
104	Laboratory Hoods	PM-10, VOC'S	yes	A.A.C. R18-2-101.54.j
105	Bathroom Vents by Labs	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
106	Electric & Instrument Battery Charging	H2SO4	yes	A.A.C. R18-2-101.54.j
107	Main Transformers(Plus the Two Following Items)	VOC'S	yes	A.A.C. R18-2-101.54.j
108	Stand -By/Auxiliary Transformers	VOC'S	yes	A.A.C. R18-2-101.54.j
109	Switchyard Transformers/gear	VOC'S	yes	A.A.C. R18-2-101.54.j
110	Sewage Treatment Plant (No incinerator)	CL2, H2S, VOC'S	yes	A.A.C. R18-2-101.54.j
111	PWS Hypochlorinators	CL2	yes	A.A.C. R18-2-101.54.j
112	Rotary Blower Pump Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
113	Degasifier Transfer Pump Vent(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
114	Cooling Water Sump Pump Vents(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
115	PWS Booster Pump Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
116	Electro-dryer Pump Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
117	Flammable Storage Cabinets	VOC'S	no	112(r)
118	Glycol Feed Pumps Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
119	Emergency Cooling Water Pumps(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
120	Glycol Circ. Pumps Vents(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
121	Clear Well Sump Pump	VOC'S	yes	A.A.C. R18-2-101.54.j
122	Seal Oil Pumps(3)	VOC'S	yes	A.A.C. R18-2-101.54.j

No.	Insignificant Activities	Pollutants	Verification	Comments
123	Turbine Lube Oil Pumps(3)	VOC'S	yes	A.A.C. R18-2-101.54.j
124	AC Equipment	CFC'S /HCFC'S	yes	A.A.C. R18-2-101.54.j
125	Misc. Lube Oil Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
126	Feedwater Heater Shell Side Vents	PM-10	yes	A.A.C. R18-2-101.54.j
127	Ash Sluice Vents (3)	PM-10	yes	A.A.C. R18-2-101.54.j
128	Mech. Dust Collectors	PM-10	no	Permitted activity
129	Filter Cleaning Bldg.	PM-10	yes	A.A.C. R18-2-101.54.j
130	Scrubber Control Room Vent	PM-10	yes	A.A.C. R18-2-101.54.j
131	Absorber Tank	PM-10 (LIME)	no	A.A.C. R18-2-730.A.1
132	Absorber Feed Pump (3)	VOC'S	yes	A.A.C. R18-2-101.54.j
133	Absorber Feed Pump(4), Scrubber Feed Pump(4)	VOC'S	yes	A.A.C. R18-2-101.54.j
134	Quencher Feed Pump(2)	VOC'S	yes	A.A.C. R18-2-101.54.j
135	Portable Welders	PM-10	yes	A.A.C. R18-2-101.54.j
136	Absorber Area Sump Pump Vent (2)	VOC'S	yes	A.A.C. R18-2-101.54.j
137	Sludge Disposal Pumps (4)	VOC'S	yes	A.A.C. R18-2-101.54.j
138	Flyash Hopper Diffuser Blowers (2)	VOC'S	yes	A.A.C. R18-2-101.54.j
139	Warehouses (2) Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
140	WAREHOUSES (2) BLDG VENTS	PM-10	yes	A.A.C. R18-2-101.54.j
141	Bechtel Construction Bldg. Br Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
142	Auto Shop Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
143	General Water Bldg. Vent	PM-10, VOC'S	yes	A.A.C. R18-2-101.54.j
144	Slurry Disposal Bldg. Vents	PM-10, VOC'S	yes	A.A.C. R18-2-101.54.j
145	Slurry Disposal Pumps Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
146	Bottom Ash Disposal Vents	VOC'S	yes	A.A.C. R18-2-101.54.j
147	Coal Handling Bldg. Vents	N-M HYDROCARBONS, PM-10	yes	A.A.C. R18-2-101.54.j
148	Paint Shop Bldg. Vent	PM-10, VOC'S	no	A.A.C. R18-2-730.F
149	E&I Room Vents	H2SO4	yes	A.A.C. R18-2-101.54.j
150	Machine Shop Vent	PM-10,VOC'S	yes	A.A.C. R18-2-101.54.j
151	Maintenance Bldg. Vents	PM-10, VOC'S	yes	A.A.C. R18-2-101.54.j
152	Maintenance Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
153	Planning Bldg. Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.i
154	Admin. Bldg. (Old) Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
155	Admin. Bldg. (New) Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
156	Admin. Bldg (Old) Water Heater Vents		yes	A.A.C. R18-2-101.54.j
157	Admin. Bldg (New) Water Heater Vents		yes	A.A.C. R18-2-101.54.j
158	Portable Generators/pumps	VOC'S	yes	A.A.C. R18-2-101.54.j
159	Stack Test Sampling Trailer	SO2, NOX, PART.	yes	A.A.C. R18-2-101.54.i
160	Guard Houses (2)	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
161	Security Building Bathroom Vents	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
162	Microwave Building Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
163	Unit 1 Sedi Pump Vent	VOC'S	yes	A.A.C. R18-2-101.54.j
164	Unit 2,3, &4 Batch Oil Tank	VOC'S	yes	A.A.C. R18-2-101.54.j
165	Soot Blowing Air Compressors	PM-10, VOC'S	yes	A.A.C. R18-2-101.54.j
166	Building and Yard Maintenance Fac.	PM-10,VOC'S	yes	A.A.C. R18-2-101.54.a
167	500 Kv Control Building Vent	N-M HYDROCARBONS	yes	A.A.C. R18-2-101.54.j
168	Bulldozer Maintenance Shed	VOC'S	yes	A.A.C. R18-2-101.54.j
169	Cathodic Protection System	CL2	yes	A.A.C. R18-2-101.54.j
170	Freon Recovery Equipment	CFC's/HCFC'S	no	602 (a) & (b)
171	Accidental Releases	VARIOUS	no	112(r)
172	Spray Painting - Architectural Appl.	PM-10,VOC'S	no	A.A.C. R18-2-727
173	Sand Blasting	PM-10	no	A.A.C. R18-2-726

APPENDIX "A": EMISSIONS EVALUATION WITH WEPCO APPROACH

Plant Name: Cholla Power Plant
Unit Number: 1
Project: CVERP
Scheduled Start of Construction Date: July, 2007
Baseline Period: 2002-2003
Post Change Period: 2007-2009

PSD Emissions Evaluation - WEPCO

Pollutant	Actual Emissions (Baseline Period)[1]	Future Expected Emissions	Potential Increases To Expected Emissions That Could Have Been Accommodated During Baseline Due to Changes in Coal Quality[2]	Representative Actual Emissions (Post Change Period)[3]	Net emissions increase or decrease	Significant Increase Threshold	Significant increase Yes/No
Carbon Monoxide - Tons	113	121	8	113	0	100	No
Nitrogen Oxides - Tons	1823	1823	0	1823	0	40	No
Sulfur Dioxide - Tons	875	1061	186	875	0	40	No
Particulate Matter - Tons	57	57	0	57	0	25	No
Particulate Matter < 10 microns - Tons	57	57	0	57	0	15	No
VOC - Tons	0.2	0.2	0.0	0.2	0	40	No
Lead - Tons	0.01	0.01	0.00	0.01	0	0.6	No
Fluorides - Tons	2	2	0	2	0	3	No
Sulfuric Acid Mist - Tons	1	1	0	1	0	7	No

Relevant Historical and Projected Operational Data

Parameter	Baseline Period	Pre Change Capacity	Projected Post Change Period
SO2 LB/Mbtu Stack Emission Rate	0.20	0.26	0.24
NOx LB/Mbtu Stack Emission Rate	0.41	0.45	0.41
PM LB/Mbtu Stack Emission Rate	0.01	0.09	0.01
Lead Concentration in Coal - ppm	5.50		6.58
Fluoride Concentration in Coal - ppm	53.30		69.21
Coal btu/LB	9801	9150	9154
Capacity Factor	84.3%		84.3%
Equivalent Availability Factor %	94.0%		

Foot Notes:

1. SO2 and Nox emissions are from Acid Rain Program. PM is calculated based on stack test data and fuel consumption data. CO is calculated from EPA-42 emission factor. VOC, lead, and fluorides (hydrogen fluoride) was calculated using EPRI emission factors. Sulfuric Acid Mist was determined using emissions factors provided by Southern Company.
2. Regulations allow adjustments to emissions based on variances in coal quality i.e. increases or decreases in sulfur content, heating values, etc. that could have been accommodated during the baseline years. Therefore, emission increases were calculated using the difference between the actual coal quality during the baseline period and the anticipated coal quality going forward.
3. Representative Actual Emissions were calculated assuming the same capacity factor as in the baseline period, expected coal heating value, and while operating at the new expected emission rates.

Plant Name: Cholla Power Plant
Unit Number: 2
Project: CVERP
Scheduled Start of Construction Date: July, 2008
Baseline Period: 2002-2003
Post Change Period: 2008-2010

PSD Emissions Evaluation - WEPCO

Pollutant	Actual Emissions (Baseline Period)[1]	Future Expected Emissions	Potential Increases To Expected Emissions That Could Have Been Accommodated During Baseline Due to Changes in Coal Quality[2]	Representative Actual Emissions (Post Change Period)[3]	Net emissions increase or decrease	Significant Increase Threshold	Significant increase Yes/No
Carbon Monoxide - Tons	247	256	9	247	0	100	No
Nitrogen Oxides - Tons	3569	3569	0	3569	0	40	No
Sulfur Dioxide - Tons	1408	2250	842	1408	0	40	No
Particulate Matter - Tons	131	131	0	131	0	25	No
Particulate Matter < 10 microns - Tons	131	131	0	131	0	15	No
VOC - Tons	0.5	0.5	0.0	0.5	0	40	No
Lead - Tons	0.02	0.02	0.00	0.02	0	0.6	No
Fluorides - Tons	4	4	0	4	0	3	No
Sulfuric Acid Mist	17	17	0	17	0	7	No

Relevant Historical and Projected Operational Data

Parameter	Baseline Period	Pre Change Capacity	Projected Post Change Period
SO2 LB/Mbtu Stack Emission Rate	0.15	0.24	0.24
NOx LB/Mbtu Stack Emission Rate	0.38	0.45	0.38
PM LB/Mbtu Stack Emission Rate	0.01	0.10	0.01
Lead Concentration in Coal - ppm	5.50		6.58
Fluoride Concentration in Coal - ppm	53.30		69.21
Coal btu/LB	9480	8800	9154
Capacity Factor	78.6%		78.6%
Equivalent Availability Factor %	89.2%		

Foot Notes:

1. SO2 and Nox emissions are from Acid Rain Program. PM is calculated based on stack test data and fuel consumption data. CO is calculated from EPA-42 emission factor. VOC, lead, and fluorides (hydrogen fluoride) was calculated using EPRI emission factors. Sulfuric Acid Mist was determined using emissions factors provided by Southern Company.
2. Regulations allow adjustments to emissions based on variances in coal quality i.e. increases or decreases in sulfur content, heating values, etc. that could have been accommodated during the baseline years. Therefore, emission increases were calculated using the difference between the actual coal quality during the baseline period and the anticipated coal quality going forward.
3. Representative Actual Emissions were calculated assuming the same capacity factor as in the baseline period, expected coal heating value, and while operating at the new expected emission rates.

Plant Name:	Cholla Power Plant
Unit Number:	3
Project:	CVERP
Scheduled Start of Construction Date:	July, 2009
Baseline Period:	2001-2002
Post Change Period:	2009-2011

PSD Emissions Evaluation - WEPCO

Pollutant	Actual Emissions (Baseline Period)[1]	Future Expected Emissions	Potential Increases To Expected Emissions That Could Have Been Accommodated During Baseline Due to Changes in Coal Quality[2]	Representative Actual Emissions (Post Change Period)[3]	Net emissions increase or decrease	Significant Increase Threshold	Significant increase Yes/No
Carbon Monoxide - Tons	254	275	21	254	0	100	No
Nitrogen Oxides - Tons	3422	3422	0	3422	0	40	No
Sulfur Dioxide - Tons	9214	1210	0	1210	(8004)	40	No
Particulate Matter - Tons	79	79	0	79	0	25	No
Particulate Matter < 10 microns - Tons	79	79	0	79	0	15	No
VOC - Tons	0.5	0.5	0.0	0.5	0	40	No
Lead - Tons	0.01	0.01	0.00	0.01	0	0.6	No
Fluorides - Tons	37	4	0	4	(33)	3	No
Sulfuric Acid Mist	14	2	0	2	(12)	7	No

Relevant Historical and Projected Operational Data

Parameter	Baseline Period	Pre Change Capacity	Projected Post Change Period
SO2 LB/Mbtu Stack Emission Rate	0.98	1.20	0.12
NOx LB/Mbtu Stack Emission Rate	0.38	0.45	0.38
PM LB/Mbtu Stack Emission Rate	0.01	0.09	0.01
Lead Concentration in Coal - ppm	5.50		6.58
Fluoride Concentration in Coal - ppm	53.30		69.21
Coal btu/LB	9932	8800	9154
Capacity Factor	82.3%		82.3%
Equivalent Availability Factor %	95.1%		

Foot Notes:

1. SO2 and Nox emissions are from Acid Rain Program. PM is calculated based on stack test data and fuel consumption data. CO is calculated from EPA-42 emission factor. VOC, lead, and fluorides (hydrogen fluoride) was calculated using EPRI emission factors. Sulfuric Acid Mist was determined using emissions factors provided by Southern Company.
2. Regulations allow adjustments to emissions based on variances in coal quality i.e. increases or decreases in sulfur content, heating values, etc. that could have been accommodated during the baseline years. Therefore, emission increases were calculated using the difference between the actual coal quality during the baseline period and the anticipated coal quality going forward.
3. Representative Actual Emissions were calculated assuming the same capacity factor as in the baseline period, expected coal heating value, and while operating at the new expected emission rates.

Plant Name:	Cholla Power Plant
Unit Number:	4
Project:	CVERP
Scheduled Start of Construction Date:	July, 2008
Baseline Period:	2002-2003
Post Change Period:	2008-2009

PSD Emissions Evaluation - WEPCO

Pollutant	Actual Emissions (Baseline Period)[1]	Future Expected Emissions	Potential Increases To Expected Emissions That Could Have Been Accommodated During Baseline Due to Changes in Coal Quality[2]	Representative Actual Emissions (Post Change Period)[3]	Net emissions increase or decrease	Significant Increase Threshold	Significant increase Yes/No
Carbon Monoxide - Tons	366	389	23	366	0	100	No
Nitrogen Oxides - Tons	4764	4764	0	4764	0	40	No
Sulfur Dioxide - Tons	10143	2567	0	2567	(7576)	40	No
Particulate Matter - Tons	264	264	0	264	0	25	No
Particulate Matter < 10 microns - Tons	264	264	0	264	0	15	No
VOC - Tons	0.6	0.6	0.0	0.6	0	40	No
Lead - Tons	0.04	0.03	0.00	0.03	0	0.6	No
Fluorides - Tons	50	6	0	6	(44)	3	No
Sulfuric Acid Mist	13	3	0	3	(10)	7	No

Relevant Historical and Projected Operational Data

Parameter	Baseline Period	Pre Change Capacity	Projected Post Change Period
SO2 LB/Mbtu Stack Emission Rate	0.71	0.80	0.18
NOx LB/Mbtu Stack Emission Rate	0.38	0.45	0.38
PM LB/Mbtu Stack Emission Rate	0.01	0.09	0.01
Lead Concentration in Coal - ppm	5.50		6.58
Fluoride Concentration in Coal - ppm	53.30		69.21
Coal btu/LB	9745	8800	9154
Capacity Factor	81.2%		81.2%
Equivalent Availability Factor %	91.3%		

Foot Notes:

1. SO2 and Nox emissions are from Acid Rain Program. PM is calculated based on stack test data and fuel consumption data. CO is calculated from EPA-42 emission factor. VOC, lead, and fluorides (hydrogen fluoride) was calculated using EPRI emission factors. Sulfuric Acid Mist was determined using emissions factors provided by Southern Company.
2. Regulations allow adjustments to emissions based on variances in coal quality i.e. increases or decreases in sulfur content, heating values, etc. that could have been accommodated during the baseline years. Therefore, emission increases were calculated using the difference between the actual coal quality during the baseline period and the anticipated coal quality going forward.
3. Representative Actual Emissions were calculated assuming the same capacity factor as in the baseline period, expected coal heating value, and while operating at the new expected emission rates.